MEASURING FRAC-PACK CONDUCTIVITY AT RESERVOIR TEMPERATURE AND HIGH CLOSURE STRESS

A Thesis

by

PRESTON XAVIER FERNANDES

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2009

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Ding Zhu
Committee Members,	A. Daniel Hill
	Yuefeng Sun
Head of Department,	Stephen A. Holditch

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ABSTRACT

Measuring Frac-pack Conductivity at Reservoir Temperature

and High Closure Stress. (August 2009)

Preston Xavier Fernandes, B.S., Texas A&M University

Chair of Advisory Committee: Dr. Ding Zhu

Ultra-deepwater reservoirs are important non-conventional reservoirs that hold the potential to produce billions of barrels of hydrocarbons but present major challenges. Hydraulic fracturing or frac-packing high permeability reservoirs is different from the conventional hydraulic fracturing technology used in low permeability formations. While the main purpose of the conventional technique is to create a long, highly conductive path, frac-packing on the other hand is used predominantly to get past near wellbore formation damage, control sand production and reduce near wellbore pressure drop. Ultra-deepwater reservoirs are usually high temperature and high pressure with high permeabilities. Frac-packing these types of wells requires short fractures packed with high proppant concentrations. Understanding the behavior of the fracture fluid and proppant is critical to pump such a job successfully and to ensure long term productivity from the fracture.

A series of laboratory experiments have been conducted to research the different problems resulting from high temperature and pressure which negatively affect conductivity. Unlike conventional long-term conductivity measurements, we

placed the proppant into the fracture and pumped fracture fluid through it and then measured conductivity by pumping oil to represent true reservoir conditions. Proppant performance and fracture fluids clean-up during production were examined. High strength proppant is ideal for deep fracture stimulations and in this study different proppant loadings at different stresses were tested to measure the impact of crushing and embedment on conductivity.

The preliminary test results indicated that oil at reservoir conditions does improve clean-up of fracture fluid left back in the proppant pack. Increasing the proppant concentration in the fracture showed higher conductivity values even at high closure stress. The increase in effective closure stress with high temperature yielded significant loss in conductivity values as compared to those obtained from industry tests.

DEDICATION

To my parents, Peter and Jovita, for all the love, support and blessings they have given me throughout my life. To my sister, Joyce, and friend, Sherrine, for all the helpful advice and encouragement offered when times were tough.

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CHAPTER I

INTRODUCTION

1.1 Hydraulic Fracturing in Ultra-Deepwater Reservoirs

With the increase in consumption of hydrocarbons and decrease in conventional oil reserves, the world has had to look to unconventional reservoirs to fill the gap. An unconventional reservoir contains hydrocarbons that are difficult to produce from. They usually require a higher degree of technology to drill, complete, stimulate, and produce it's resources. Hydrocarbons from shale gas, tight gas sands, oil shales and ultra deepwater wells are examples of unconventional reservoirs.

Ultra-deepwater reservoirs have the potential to produce billions of barrels of hydrocarbons from the deep buried formations. These reservoirs are usually high temperature and high pressure with very permeable rock. The ability to produce economically from these wells is not a major concern, unlike in the case of tight gas reservoirs, but rather the problems associated with high permeability. Formation damage during drilling, the consequent high near wellbore pressure drop and the production of sand, which can lead to failure of subsurface equipment, are some of the key issues with producing from these reservoirs. While in most wells hydraulic fracture stimulation is used to create a high conductivity path deep into the formation, in high permeability reservoirs, it does provide an improved connectivity between the wellbore and reservoir by bypassing damage but it also helps tackle some of the issues.

This thesis follows the style of *SPE Journal*.

The idea of hydraulic fracturing and gravel packing for sand control was first put into practice in the 1970's in Venezuela. The fracture treatment was carried out using a viscous crude (10-20 cP) and sand sized to control formation sand. A screen was then washed down and sand was placed around it (Roodhart et al. 1993). Since then, the technology has evolved considerably and several hundred are performed every year in various petroleum regions such as the Gulf of Mexico, Prudhoe Bay (Alaska), Indonesia, Nigeria, Australia and the North Sea. Currently, many different types of fracturing fluids are used with the most common being salt-based polymers with the use of cross-linkers. It was not until the early 1970's that cross-linkers were introduced with the purpose of increasing the viscosity of gelled water base fracturing fluid without increasing the polymer concentration. This helps carry proppant downhole into the fracture. In addition, different kinds of additives have also been used in fracturing fluids to compensate for different reservoir conditions such as high temperature, presence of clay, extensive pumping time, etc.

The main idea behind a frac-pack job is to create a short fracture which is then packed with proppant, increasing its width. As shown in Fig. 1.1, the first step in this stimulation job requires the pumping of a clean fracture fluid above the fracture gradient of the formation. This initial volume, pad, helps initiate the fracture and provides sufficient width in the near wellbore region to allow proppant-laden fluid to enter the fracture. In the case of the frac-packs, only a short fracture beyond formation damage is desired and thus the initial fluid has to have a low polymer concentration, so that it dehydrates, leaks off, quickly into the formation. The next stage is the proppant

laden fluid. This stage serves to transport propping agent into the fracture. This stage is usually broken up into 3 or 4 smaller stages, with each stage having a higher proppant concentration than earlier. While the pad leaks off into the formation, proppant will reach the tip of the fracture. As solids cannot propagate a fracture, once the pad has leaked off, the proppant bridges off at the tip. This event is called a tip screen out and is the key to a successful frac-pack operation. Once the proppant has bridged out at the tip, it starts packing up along the fracture, back to the wellbore. More proppant is pumped in and the net pressure increase causes the width to expand.

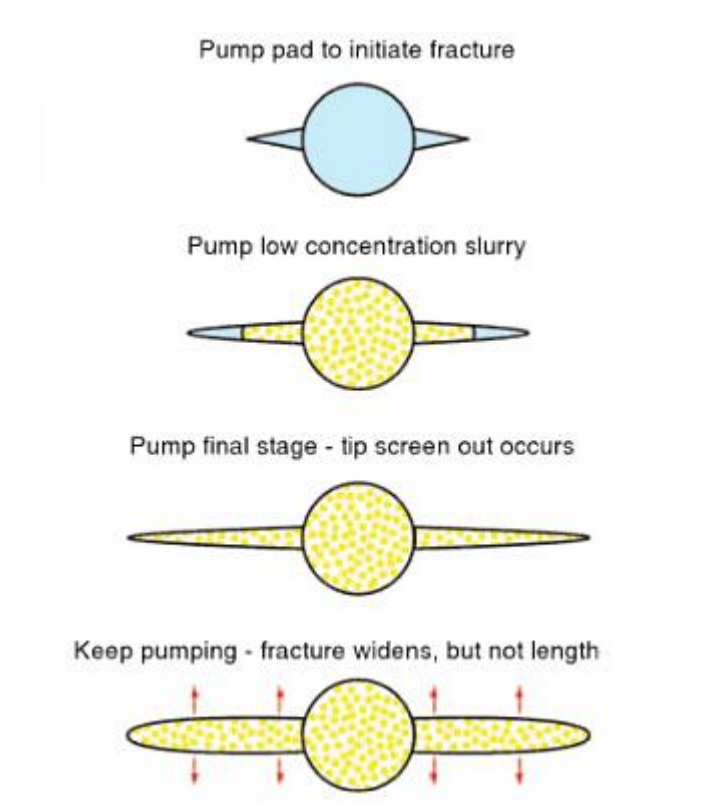


Figure 1.1- Tip screen out or frac-pack process (Bellarby 2009)

In high permeability fracture stimulations, fracture length, fracture width and conductivity are the main criteria taken into consideration when designing an optimal fracture treatment. Fracture length is optimized in order to bypass near wellbore damage, and provide a highly conductive path for the reservoir. Frac-packs with their wide, high proppant concentration fractures help control sand production by reducing near-wellbore pressure drawdown and flow velocities, increasing the effective stresses around the wellbore (by compacting and stabilizing the sandface) and acting as a filter during production (Aggour 2001). They are found to increase conductivity which yields better well productivity. Frac-packs also provide better zonal coverage of laminated reservoirs and non-perforated zones. Common factors that hinder long-term fracture conductivity are gel residue, proppant crushing, fines migration, proppant embedding, etc which are caused mainly due to high temperature and high closure stress.

Considering the high costs involved in drilling, completing and producing these ultra deepwater wells, it is important for these wells to produce many years down the line. Therefore understanding some of the issues leading to the loss of productivity and implementing ways to counteract them becomes the need of the hour.

1.2 Literature Review

Studying fracture conductivity has been taking place in the industry ever since the inception of the hydraulic fracturing technology. With the goal being to create a highly conductive path in a low or high permeability reservoir, attaining a successful hydraulic fracture is paramount to ensuring a well is economic. Conductivity is usually measured by varying proppant concentration, polymer concentration, temperature and closure stress. The early standard procedure for measuring short-term conductivity of proppant packs was developed by the American Petroleum Institute (API) using a Cooke Conductivity Cell. This was documented in API-61 (1989). For years, this procedure along with a few revisions came to become the standard for long-term testing of proppant packs.

In 1987, Stimlab made three changes on API RP 61 to get better results (Much and Penny 1987). Instead of the steel pistons, Ohio sandstones were used; the temperature was changed to either 150°F or 250°F and a known proppant concentration (generally 2 lb/ft2) was placed between the cores with stress maintained for 50 hours. It was found that these changes reduced the measured conductivity by as much as 85%, depending on proppant quality and test conditions (Palisch et al. 2007). In 2007, this standard for long-term testing came to be known as the ISO 13503-5 (Kaufman et al. 2007).

Seccombe and Anderson (1982) and Reinicke et al. (1985) showed through post-frac analysis that actual conductivity values were significantly lower than those

predicted by laboratory experiments for the same proppant. The post-frac values usually differed by a factor of 0.1 to 0.5 times the laboratory data.

McDaniel (1986) conducted a series of experiments evaluating the effect of subjecting proppant to extended periods at different closures stresses and varying temperature between 75 °F and 275 °F. Laboratory tests of conductivity at ambient temperature and short times were found to be optimistic and when severe test conditions were held for 10 to 14 days, a correction factor of 0.47 to 0.54 had to be used for synthetic proppants.

Schubarth et al. (1997) performed a study using a pseudo three dimensional simulator to examine the magnitude of excess closure stress on proppant. They showed that the closure stress after creating a propped fracture was higher than the in-situ stress of the undamaged rock calculated from a mini-frac. This excess stress further reduces the conductivity of the proppant pack below values estimated through current testing.

As a well is produced it undergoes constant production and shut-in cycles. In 1991, the effect of cycling closure stress on proppant packs was studied (Ouabdesselam and Husdon, 1991). They placed Ottawa sand and intermediate strength proppant in 2 lb/ft2 concentrations between different sandstones and cycled closure stress multiple times between 2000 psi and 10,000 psi, measuring conductivity with brine at 150 ºF. They found that permeability impairment and pack width reduction takes place due to fatigue failure of the proppant, fines migration and embedment. Stephens et al. (2007) studied the main contributing factors in the loss of fracture conductivity. They ran the AP1-60 crush resistance test at pressures of 6000, 8000 and 10,000 psi and found that

the first cycle caused the greatest compaction of all the cycles. Size distribution and mechanical strength of proppant plays a bigger role than ramp and release rates of closure stress. Cyclic stress loading creates fines and allows for the proppant motion and redistribution which leads to compaction and loss of conductivity. Although these tests provided valuable information, they did not take the higher temperature aspect into consideration.

In 2009, Freeman studied the effect of high temperature, closure stress and fluid saturation on proppant crushing. Two crush resistance tests were performed using high strength bauxite at 15,000 and 20,000 psi and 400 ºF and 500 ºF. It was found that pressurized fluid saturation, increased temperature and extended stress loading, increase the occurrence of proppant failure (Freeman et al., 2009).

At present, there is significant information available on the behavior of low proppant concentration packs at temperatures and pressures equivalent to ultra-deepwater reservoirs. However, there is very little data on the behavior of high proppant concentration packs at different closure stress. In addition, the use of 2% KCl to simulate reservoir fluid is not very accurate. This research, therefore, will conduct a series of experiment using a 10 cp mineral oil with the appropriate viscosity to study gel clean-up in the proppant pack, the behavior of high proppant concentrations at different closure stresses and to identify the effect of crushing and embedment on long-term conductivity in these packs.

1.3 Problem Description

With the extremely high costs associated with developing ultra deepwater reservoirs, maintaining economic long term production becomes a key component in deciding to go forward with a project. Fracture conductivity and fracture width are two of the more important attributes that determine the success of a fracturing treatment in high permeability formations.

Fracture conductivity is affected by many variables such as polymer type, proppant type, effective closure stress, temperature and production rate. Different polymers are chosen for stimulation because of their ability to increase and hold fluid viscosity at different temperatures and pressures, thereby helping in proppant transport from the surface to the fracture tip. However, it is also known that the cross-linked polymer chains are difficult to breakdown which can damage/reduce the formation's permeability and proppant pack conductivity. In addition to this, in deep reservoirs, the mechanical properties of the proppants are tested at higher closure stresses and this sometimes leads to proppant crushing and embedment. These can lead to lower long-term conductivity which equates to lower productivity in high permeability formation. There are publications that study long term conductivity of fracture at different closure stresses but there is a lack of publications which test these proppants under realistic stimulation conditions, with cross-linked fracture fluid, at high temperature and with mineral oil for clean up.

In this study, laboratory tests were carried out using different concentrations of high-strength proppant to study the effects of increasing closure stress on proppant

crushing, embedment and their effect on fracture conductivity. Deep reservoirs result in high overburden stresses and fracturing this kind of reservoirs requires a higher concentration of proppant to keep the fracture open and make it economical. The higher viscosities of cross-linked gel is favorable to transport proppant down hole, but it also causes reduced conductivity due to the gel being left behind. In this study, an experimental apparatus will be developed to simulate fracturing conditions of ultra-deep wells. The fracture fluids and proppant will be examined for their effect on fracture conductivity. Gel damage in such a fracture treatment will be investigated and long term fracture conductivity will be measured to identify the treatment conditions and materials that could result in sustained fracture conductivity. This test measures the clean-up efficiency of the gel and long-term conductivity of the proppant pack using a 10cp mineral oil at reservoir conditions.

1.4 Research Objective

This research had three main objectives:

1. Set up the experimental apparatus and procedure that will be used to study the effect of long-term high temperature and high closure stress on proppant pack conductivity. High temperature mineral oil is pumped through the cell to simulate reservoir flow and measure conductivity.
2. Conduct experiments to see the effect of closure stress and high proppant concentrations on conductivity.
3. Identify the difference between a short-term and long-term conductivity test

By achieving the above objectives, this research was able to predict with higher accuracy the long term conductivity of a frac-pack completion in a well drilled in an ultra deepwater reservoir. Additionally, this study aids in the further testing of proppant packs of varying proppant concentrations with conditions, such as higher temperatures and closure stresses, and fracture fluids that accurately represent reservoir conditions and the planned stimulation job.

CHAPTER II

EXPERIMENTAL SET UP, PROCEDURES, AND CONDITIONS

2.1 Experimental Apparatus

In 1989, API designed a standardized conductivity measurement setup to provide comparable and repeatable results from tests conducted by different labs. In this setup, proppant was placed manually between the core samples and conductivity measurements were taken by pumping a fluid through the setup, measuring differential pressure across the cell. As this practice was not a very accurate representation of the field conditions, Marpaung (2007) developed an apparatus which provides the ability to pump proppant or fracture fluid through the cell. The purpose of developing such a setup was to provide appropriate scaling to symbolize field conditions experimentally, with flexibility for further studies of gel damage, fluid cleanup and proppant behavior.

The conductivity setup is used for this study can be broken up into three different setups:

- Fracture fluid pumping
- Simulated oil production
- Fracture conductivity

2.1.1 Fracture Fluid Pumping

The fracture fluid pumping apparatus consists of the following (Fig 2.1):

- A mixing tank - to prepare the cross-linked fluid
- High pressure centrifugal pump
- Heating jacket - to increase the temperature to reservoir conditions
- Modified API RP-61 fracture conductivity cell (API 1989)
- A load frame to apply a set load stress
- Leakoff fluid collector
- Data acquisition system
- Waste barrel

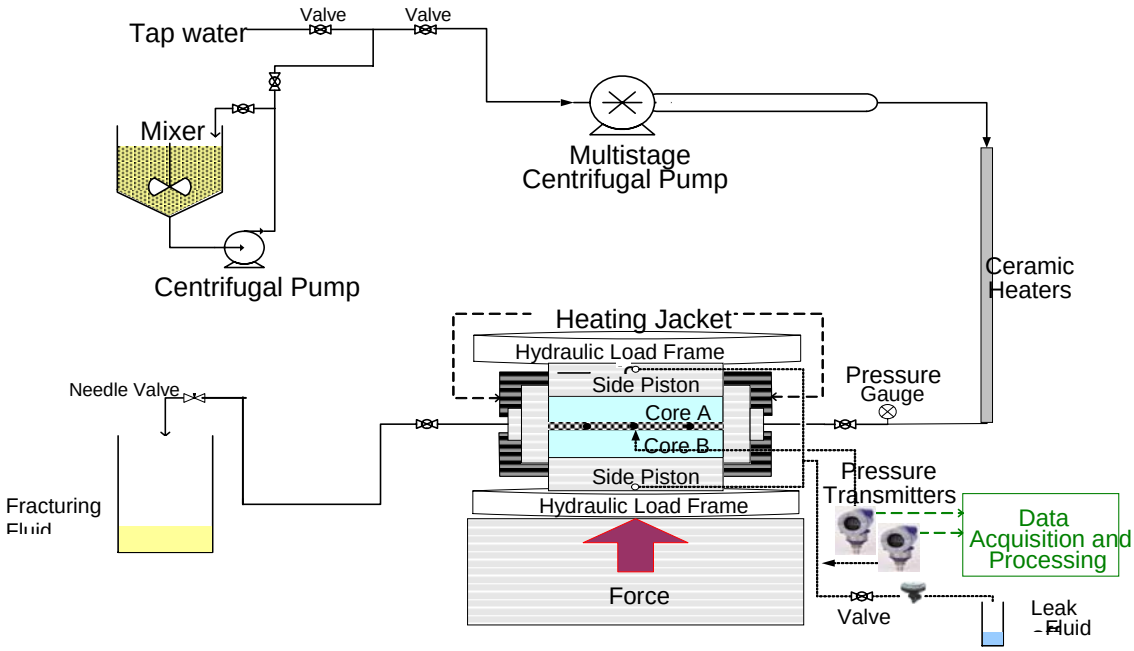


Figure 2.1- Pumping schematic of fracture fluid pumping (Fivman 2007)

Fig. 2.1 shows the schematic for the pumping apparatus. There is one metal tank in the inlet of the pump, in which the fracture fluid is mixed and pumped from. A heating jacket heats the cell to the desired experimental conditions. The temperature used in the experiments was 235 ºF. A back pressure (or pressure differential across the cell) as maintained during the pumping to enable leak-off through the core.

2.1.2 Simulated Oil Production

The apparatus that is used to simulate oil production and measure fracture conductivity through the cell contains:

- Oil Bath – Labnics 1000T
- Variable Speed Positive Displacement Gear Pump
- Kobold Positive Displacement Flow meter
- A modified API RP-61 fracture conductivity cell
- Load Frame
- Pressure Transducers
- Data acquisition system

The schematic of the apparatus for conductivity measurements is shown in Fig. 2.2. Oil was used in the experiment as producing fluid. The oil has a viscosity of 320 cp at room temperature. An oil bath is used to heat the oil to 210 ºF, and the viscosity is 10 cp as this temperature. Oil was circulated through the cell in a loop via a variable speed centrifugal pump. The cell was heated with the help of a heating jacket to 235 ºF. Conductivity was measured by flowing oil through the proppant packed in between the core samples and measuring the pressure drop across the fracture under different stress conditions. The measurements were taken from 8- 20 hours to see the long-term decline in conductivity.

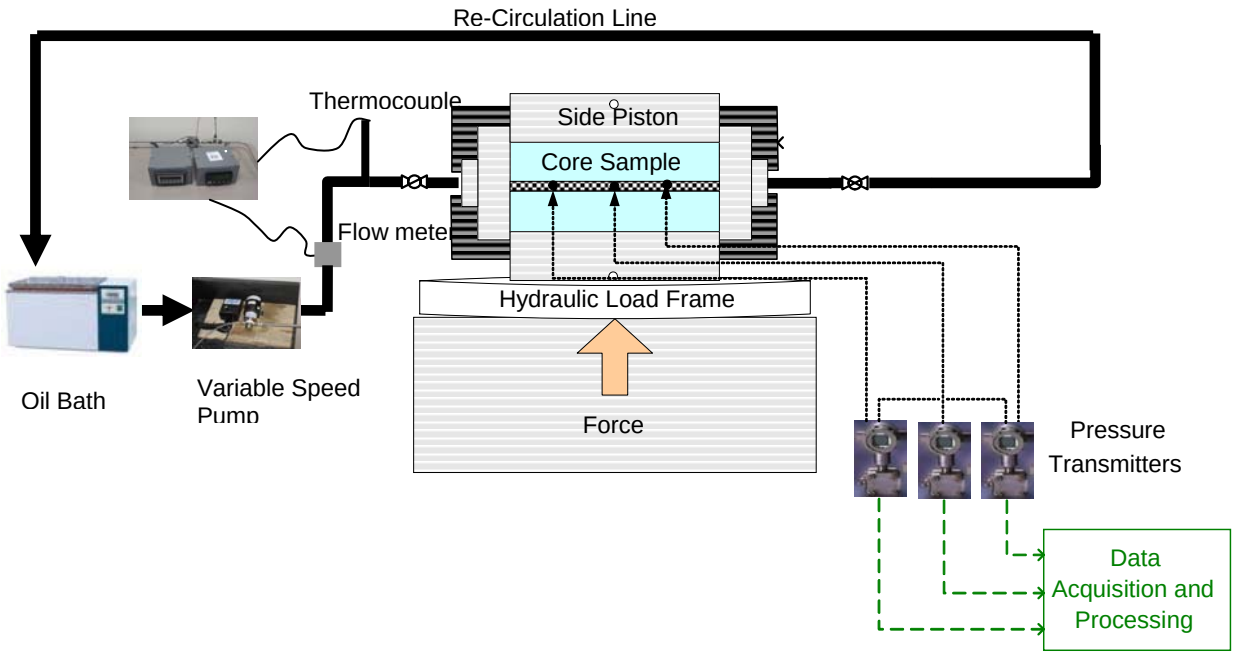


Figure 2.2- Schematic of fracture conductivity apparatus

Fig. 2.3 shows the modified API RP-61 conductivity test cell and a typical core sample. Dimensions of the cell body are 10 in. long, 3-1/4 in. wide and 8 in. tall. The two side pistons in the cell, with the Viton polypack seals, are used to keep the cores in place, hold leakoff pressure and prevent any leakage. The cell is made of stainless steel (SS 316) and has a special internal structure consisting of a rounded edge to accommodate the core samples. The cores used in this study have a rectangular shape with rounded edges to provide the best fit of the core inside the cell. Dimensions of a core sample are 7 in. long, 1.7 in. wide and 3 in. height.

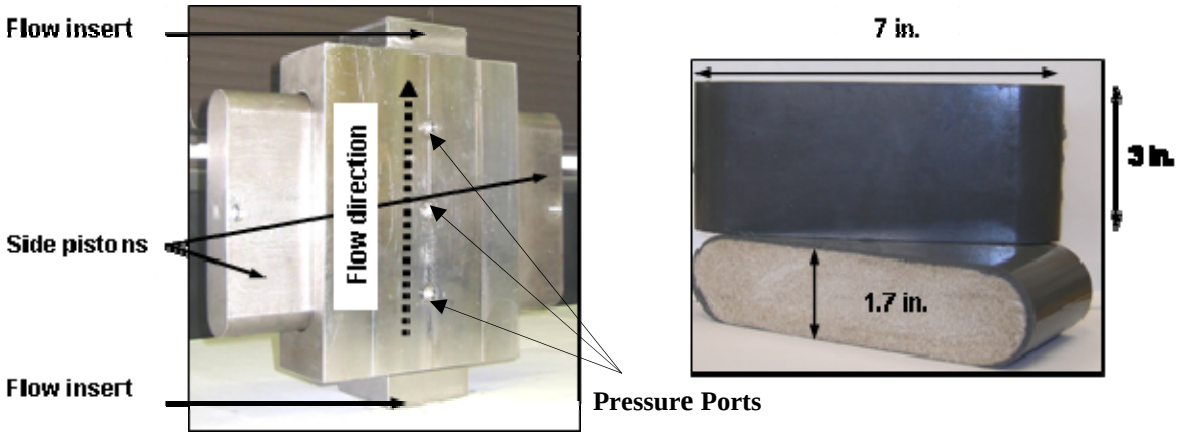


Figure 2.3- Conductivity cell and core sample used for experiments

The core samples were wrapped with two rows of Teflon tape which were then covered with a sealant material to provide a perfect fit inside the cell. Side pistons with o-rings on the edges are use to keep the cores in place during the experiment. These pistons have flow inserts in them to connect the flow lines. To measure conductivity,

the pressure difference across the cell is measured. To enable this there are three access ports on the side of the cell body which connect to pressure transducers which can record data automatically. The first and third ports measure the pressure difference across the fracture, while the second port measures the cell pressure throughout the experiment. A hydraulic load frame is used to provide the closure stress for each test. The loading frame can apply up to 25,000 psi closure stress. It has a ram area of 125 in^2, so there is about 10 times the force applied to the load frame is actually acting on the core samples which have a ram area of 12.2 in^2.

2.1.3 Surface Characterization

The profilometer apparatus (Fig. 2.4) is used to characterize the surface profile of the rock. A profilometer is a precision vertical distance measurement device which can measure small surface variations in vertical surface topography as a function of the surface position. The vertical measurement is made with a laser displacement sensor while the sample is moved along its length with the help of a moving table. This measurement is repeated several times over the length of the sample to cover the entire surface area.

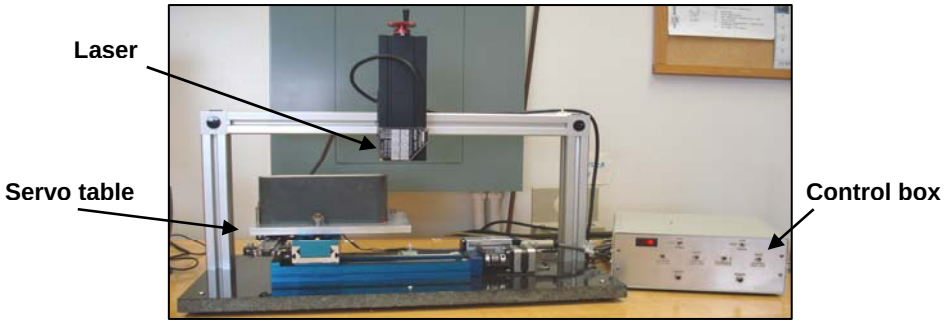


Figure 2.4- Profilometer device

In this experiment, the surface scanning was performed after conductivity measurements. The surface profile before and after conductivity measurements were studied to study the extent of proppant embedment and see if it plays a role.

2.2 Experimental Procedure

The experimental procedure consists of six main steps as shown in Fig. 2.5. The description of each step is listed below.

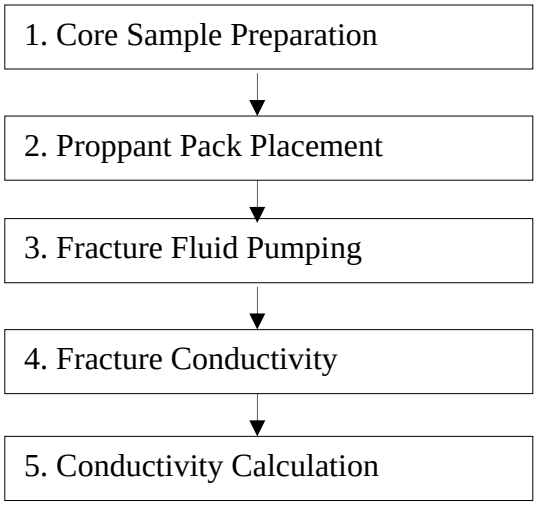


Figure 2.5- Experimental process for frac-pack conductivity testing

2.2.1 Core Sample Preparation

The core sample used in this experiment was Berea sandstone. This rock was chosen because of its high permeability and strength, which closely represented the reservoir in this study. The rock samples were custom cut into a rectangular shape with round edges using an electric cutter machine. To provide a perfect fit and better seal inside the conductivity cell the core samples were covered with a silicone-base sealant. Core samples before and after covered with silicone rubber are shown in Fig. 2.6.

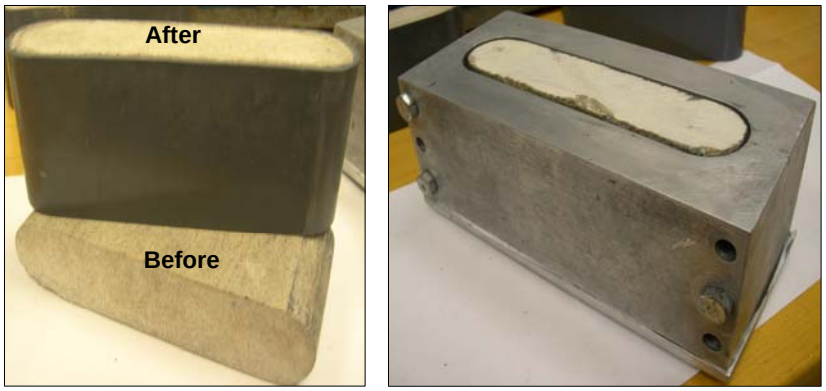


Figure 2.6- Core samples and mold used to prepare the core samples

The procedure to prepare the core samples is:

1. Prepare and clean the rock samples that need to be molded.
2. Put blue tape on the top and bottom of the core sample, cutting the edges with a razor cutter.
3. Apply silicone primer (SS415501P), about three times with a brush, along the edges of the core samples. Allow 15 minutes waiting time in between primer applications.

4. The mold, shown in Fig. 2.5, is made of stainless steel, with a plastic bottom. Clean the metal surface and bottom plastic piece of the mold with acetone using a cloth.
5. Spray Sprayon S00315 on the metal molds three (3) times. Wait for two (2) minutes between each spray.
6. Assemble the mold. Tighten the four screws at the bottom and the three screws on the side. Make sure all bolts are tight.
7. Put the rock in the mold and adjust to center position.
8. Prepare 75 cc of silicone potting compound and 75 cc of silicon curing agent from the RTV 627 022 kit for a 1:1 mixing ratio. Weigh before mixing both components to ensure that the mixture is 50/50 of each component, either by volume or by weight percent. Mix and stir it thoroughly.
9. With a disposal injection system inject the mixture in the gap between the core and the mold carefully until the silicone fills to the top of the core sample.
10. Remove the top duct tapes and put the molds into the oven at 100°C for approximately 1.5 hours.
11. Remove the molds from the oven and wait for two (2) hours until the molds temperature decreases.
12. Unscrew all the bolts from the mold and carefully remove the samples from the mold.
13. Cut extra silicon on the edges with a razor cutter.
14. Label the rock sample. The core sample is ready to use.

15. The core samples initially are saturated with air. Two to three hours prior to running an experiment, the core samples were saturated with the base fluid (5% KCl) using the vacuum pump and bowl as shown in Fig. 2.7. The procedure to do this is as follows:

    a. Clean the beaker to remove any old fluid and solids.

    b. Fill the beaker with 2.5 L of base fluid (in this case 5% KCl)

    c. Place the clean core samples in the beaker. *The core samples must be fully submerged.*

    d. Apply Coring High Vacuum grease along the rim of the beaker and press the lid down on it. *Make sure the lid is sealed.*

    e. Turn on Breaker #28 in Lab 808 and switch on the pump. *Check to see if bubbles are coming out of the core sample. Run this pump for only 2-3 hours.*

Figure 2.7 – Apparatus for core saturation

2.2.2 Proppant Placement

In these experiments, proppant placement between the core samples was done manually. The detail procedure for setting up the conductivity cell prior to pumping is as follow.

1. Prepare the core samples. Follow the guideline in section 2.2.1. *Only use the side of the core that has the silicon epoxy coating flush with the core sample as your fracture face. Any grooves can lead to errors in conductivity readings.*
2. Wrap each core with two rows of Teflon tape, one near the top and the other near the bottom, and apply coring grease around each row. This helps provide a seal once inside the cell.
3. Remove the o-rings and seals from the flow inserts and the side pistons and wrap some Teflon tape in the grooves. Put the seals back in.
4. Insert the bottom core sample into the bottom opening of the conductivity cell using the hydraulic jack. This core will serve as the lower fracture face in the cell. Depending on the proppant concentration, make sure the lower fracture face is either at the bottom of the pressure ports (4 lb/ft^2) or at the bottom of the side openings (8 $lb/ft^2$and 10 lb/ft^2). This ensures that the proppant pack is in the centre of the cell and both cores and side pistons can fit in properly with a good seal.
5. Put the conductivity cell on the bottom piston. Make sure the leakoff valve is open to prevent air from being trapped. Check to see that the seal on the bottom piston is inside the cell.
6. Put the conductivity cell into the support rack. Adjust bolts to fit the bottom piston.

7. Place the screen in flow insert #2 (outlet side of the cell) to prevent loss of proppant.
8. Put the side flow inserts into the cell with the numbers on the inserts matching the numbers on the cell.
9. Measure the required amount of proppant and mix with enough linear gel to soak proppant.
10. Place the proppant evenly on the lower fracture face.
11. Put the conductivity cell with the support rack in the center of the hydraulic load frame.
12. Activate the AP-1000 hydraulic pump by opening the air supply valve. Open the air regulator and adjust the supply pressure to move the bottom ram of the hydraulic load frame up or down.
13. Insert the top core sample into the conductivity cell using the hydraulic frame.
14. Place the top piston into the cell. Apply approximately 1000 psi on the cell to keep the pistons inside the cell. *The sound of the proppant pack compressing will be heard.*
15. Connect all pumping, leakoff and pressure lines into the conductivity cell. *Make sure all connections are tight.*
16. Wrap the heating jacket around the conductivity cell.
17. Set the temperature controller of the heating jacket to a predetermined temperature (235°F). Turn on the controller to heat up the heater. *Make sure no liquid falls on the heating jacket while in use.*
18. The setup is now ready for pumping.

2.2.3 Fracture Fluid Mixing and Pumping

A service company designing the fracture fluid for this project has provided the chemicals that have been used in this experiment. During the experiment, the fracture fluid is mixed concurrently with the setting up of the cell. Below is the general mixing procedure for the 5% KCl based fracture fluid:

1. Make sure the steel tank and the pipes are clean.
2. Add 5 gallons of tap water into the mixing tank. Use plastic PVC pipe with markings to measure volume in tank.
3. Add required Potassium Chloride (KCl) amount to tank, to make 5% KCl. Mix in some bactericide to clean the water.
4. Add the concentrated polymer into the mixing tank and mix the polymer solution. Mix base gel for 30 minutes to allow the gel adequate hydration time.
5. Slowly add pH Buffer until the mixing fluid reaches a pH of 9.5-10.2.
6. Other additives like surfactants, non-emulsifying agents, clay control agents are then added to the tank. Shortly after add in the breakers and breaker catalyst.
7. Finally, introduce the cross linker to the linear gel in the tank. Start pumping 5-10 seconds after adding the cross-linker
8. *Before starting the centrifugal pumps and after pumping the fracture fluid, circulate water through the pump and lines via the bypass, as shown in* Fig. 2.8, *using water from the other end of the inlet to the pump. This helps clean the lines and reduces wear on the pump.*

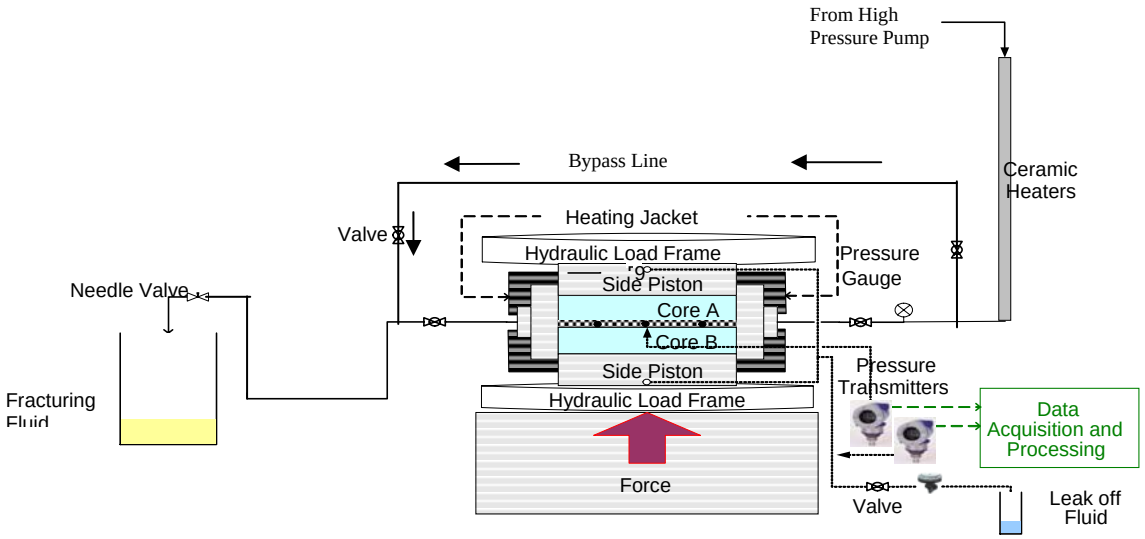


Figure 2.8 – Pumping schematic through bypass lines

9. Switch valves, close the bypass and begin pumping. *Gel begins to cross-link immediately and therefore a delay in pumping can cause difficulties in pumping the fluid through the pump and cell*.
10. To enable leakoff, hold a pressure differential (minimum 5 psi).
11. Flow the gel for one to two minutes. Make sure gel is pumped through the cell by opening the small red valve next to conductivity cell.
12. After pumping of the gel is finished, immediately close the inlet valve and outlet valve and open the bypass valve. Switch gel to water to clean the high pressure pump. Pump water for 10-20 minutes and then shut off pump and close valve to the main line.
13. Adjust the pressure on the AP-1000 hydraulic pump to obtain 3000 psi closure stress acting on the fracture
14. Let the conductivity cell sit for 3-4 hours before taking conductivity measurements.

If using 12.3 ppg NaBr based fracturing fluid, then follow steps *a-g* below and continue from step 8 above.

a. Make sure the steel tank and the pipes are clean.
b. Add 5 gallons of tap water into the mixing tank. Use plastic PVC pipe with markings to measure volume in tank.
c. Add required Sodium Bromide (NaBr) amount to tank, to make 12.3ppg NaBr. Add buffer BF-10L and mix for 60 seconds.
d. Stir the polymer solution and then add the concentrated polymer into the mixing tank. Mix base gel for 30 minutes to allow the gel adequate hydration time.
e. Slowly add pH Buffer (BF-11L) to the hydrated fluid.
f. Add in the mixture of XLW-56/C12 to tank. This delays the crosslinking. *Before starting the experiment setup the XLW-56/C12 mixture using NaOH and XLW-56 in the ratio of 1ml NaOH : 8.33ml XLW-56. The reaction is exothermic and hence should be mixed slowly not allowing the temperature to exceed 110F.*
g. Finally, the breaker (GBW-12L) and buffer (BF-9L) are mixed in the tank. Mix for about 1 – 2 minutes before pumping.

2.2.4 Fracture Conductivity Measurement

Mineral oil with a viscosity of 10 cp is used to simulate oil production and measure fracture conductivity. The conductivity is measured for long periods of time at different closure stresses to study decline over time. The procedures to measure conductivity are as follows:

1. Start the oil bath an hour before taking conductivity measurements as the oil takes time to heat up. Set the initial temperature of the oil bath to 289 ºF (143ºC). This is to heat the pipes and establish continuous flow of oil at 210 ºF (viscosity of 10 cp). Once circulation has been established the temperature can be slowly lowered to 289ºF (133 ºC).
2. Keep the conductivity cell with the support rack and heating jacket in the center of the hydraulic load frame after pumping. *Attention should be paid to the closure stress as it tends to drop as the cell heats up during conductivity measurement.*
3. Hook up the front and back pressure ports to pressure transducers B or D. Transducer D has a range of 0-10 psi and transducer B has a range of 0-30 psi. *There are four transducers attached to the setup. Transducer A measures cell pressure, Transducers B (0-30 psi), D (0-10 psi) and C (0-1500 psi) measure pressure differential. Depending on the expected pressure differential use the smallest range to avoid error.*
4. Make sure all the valves leading from the oil pump to the cell are open and the bypass valve is shut. On the outlet side, keep a valve open to drain the initial batch

of oil that is mixed with the gel. Once the oil has cleaned up, it can be circulated back into the oil bath.

5. Adjust the pressure on AP-1000 hydraulic pump to maintain at or increase to 3000 psi, the closure stress acting on the fracture. Conductivity measurements have to be taken at 3000 psi, 5000 psi, 8000 psi and 10,000 psi.
6. Start the pump and change the speed of the pump to get the desired flowrate, based on scaling calculations (Section 2.3.6). Flowrate readings are obtained from the flowmeter down stream of the pump. *The reading on the flowmeter is in ml/sec. Attention should be paid to the flowrate because as the oil heats up and viscosity decreases the flow rate keeps rising.*
7. Open LabView to record pressure differential across the cell from the pressure transducer. Open file “Hyd Conductivity Pressures Modified.vi” from folder “C:/LabView Programs/Hydraulic Fracturing/” and start recording data. LabView has already been calibrated for transducers B (0-30 psi) and D (0-10 psi) and the plots in LabView are named accordingly. Open Excel file “HydConductivity Pressures.xls” from the same folder. In the Excel Sheet, Column D displays values for transducer B and Column C displays pressures for transducer D. *Record pressure from the start of pumping.*
8. Temperature is measured by the thermocouple right before the cell. It takes about 20 minutes for the temperature of the system to reach desired temperature (210 ^{o}F) with circulation.

9. Record pressure data at each stress level until the change is small (Approximately 20 hours).
10. After running all tests disconnect all lines to the conductivity cell.
11. Lower the load frame pressure to allow the removal of the conductivity cell.
12. Remove the rock sample from the cell with the support rack and hydraulic frame.

2.2.5 Fracture Conductivity Calculation

To calculate the fracture conductivity data from the experimental data, Darcy's law equation (Equation 2.1) was used with the calculated flowrate and pressure change.

$$k_f w\ (md - ft) = \frac{\mu * q * L}{h * \Delta p} * 8035.97 \qquad (2.1)$$

The pressure drop (Δp) was recorded by LabView every 10 seconds at a set flowrate under each closure stress. The data was recorded until the Δp curve had a slope close to zero. Table 2.1 shows the values of all the other variables we used in the fracture conductivity calculation.

Table 2.1- Data used for Conductivity Calculation

μ	Oil Viscosity, cp	10
L	Length of fracture, in	5.25
h	Height of fracture, in	1.75
q	Flowrate, L/min	0.174

2.3 Experimental Conditions

In this experimental study, Berea sandstone was used to study the effect of increasing closure stress on frac-pack conductivity. Accuracy of testing and of different parameters is key for useful and successful tests. The following parameters were adopted for this experiment.

2.3.1 Fracture Fluid Composition and Conditioning

A simple fracturing fluid composition is selected and provided by a service company for this experiment. This fracturing fluid is selected by the service company to run initial tests and set up the procedure. 5% KCl was the base fluid and guar polymer is used as a base gel for this experiment. All experiments are conducted at room temperature. The composition of the fracturing fluids used for the series of experiment is shown in Table 2.2 below.

Table 2.2- Main Fracturing Fluid Chemicals

Chemical	Concentration
Polymer, Guar, lb/Mgal	37.5
pH Buffer to pH	9.5-10.2
Enzyme Breaker, gal/Mgal	2
Oxidative Breaker, lb/Mgal	0.5
Breaker activator, gal/Mgal	0.5
Borate Crosslinker, gal/Mgal	3

The components for the selected fracturing fluid are as follows:

1. Guar. Concentrated polymer guar is used to form a viscous base gel fluid.
2. pH Buffer. Is used to control pH which is important for polymer hydration rate and crosslinking rate.
3. Breaker. The purpose of breaker is to reduce the viscosity of the polymer solution and provide rapid fluid clean up. An enzyme and breaker is used in this experiment.
4. Breaker activator. Another type of oxidative breaker is used to speed up breaking time of the gel.
5. Crosslinker. To increase gel viscosity and simulate real fracture fluid for testing.

2.3.2 Proppant Size and Concentration

Proppant used in this experiment was high-strength proppant with a mesh size of 16/30. This proppant has apparent specific gravity of 3.48. High strength proppant is ceramic proppant commonly sintered bauxite. As this experiment studied fracture conductivity of proppant packs at different closure stresses, the proppant concentration was varied with each experiment. Proppant sizes were varied between 4 lb/ft^2, 8 lb/ft^2 to achieve the objectives of this research.

2.3.3 Mineral Oil

To perform conductivity analysis of different proppant packs in these experiments, mineral oil with a viscosity of 10cp was chosen. Mobile DTE 150 was the

mineral oil chosen. This was done to closely represent the reservoir fluid in the formation being studied. Fig. 2.9 below displays the viscosity curve for the oil.

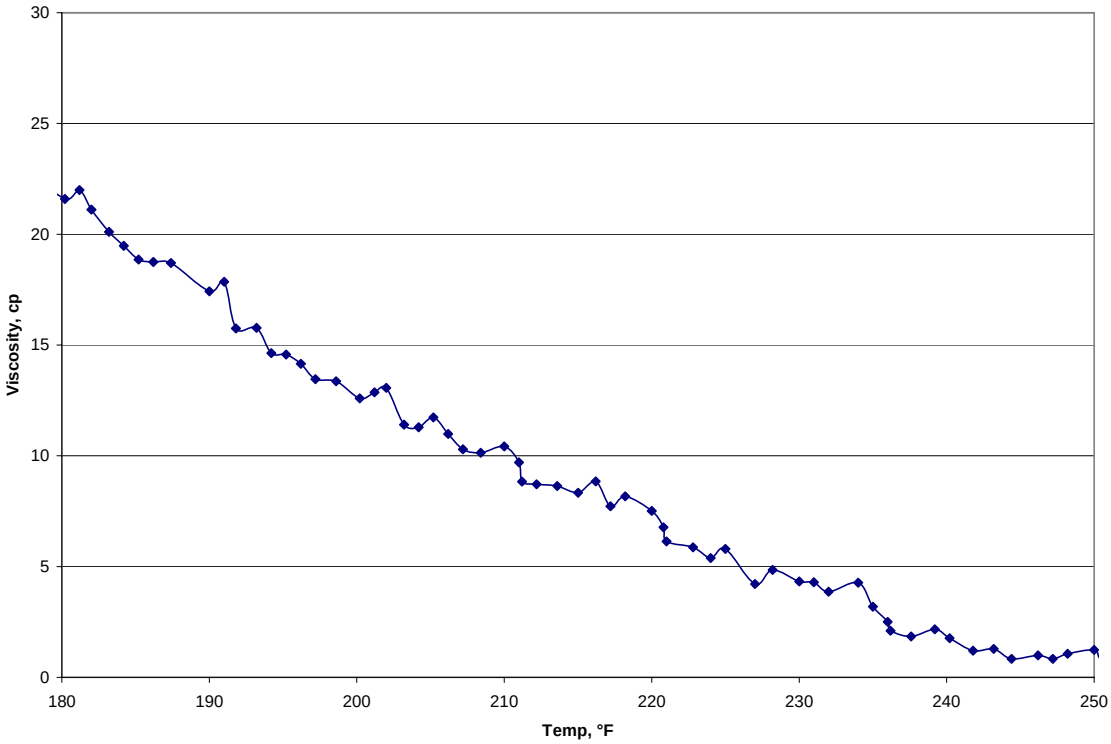


Figure 2.9 – Viscosity curve for mineral oil above 180°F

2.3.4 Polymer Concentration

In a real fracture stimulation, the purpose of using polymer is to provide fracture width and length and to transport proppant. The most commonly used gelling agent used in the industry is guar. Gel concentrations in the field usually vary from 30 to 50 lb/Mgal. In this experiment a fracture fluid with a gel loading of 37.5 lb/Mgal was used.

2.3.5 Shut-in Time

When designing the fracturing fluid, a breaking time of 3-4 hours was used to estimate breaker volumes. The breaking time is a function of the breaker volume and the shut-in time determines the effectiveness of the breaker. A shut-in time of 4 hours was selected for this experiment.

2.3.6 Temperature

Temperature affects the breaking time of the gel and also the mechanical properties of the proppant. For this series of experiments, 235°F has been selected as the cell temperature and 210°F as the temperature of the oil. This is done so as to replicate the reservoir conditions.

2.3.7 Mineral Oil Rate

Mineral oil was used in these experiments to simulate oil production from the fracture into the wellbore. A flow rate for the laboratory setup was calculated to simulate a field production rate of 7000 Bbl/D using the values from the Table 2.3 and Table 2.4 below.

Table 2.3- Laboratory Fracture Conditions

Fracture height(h)	1.75	in
Fracture width (w)	0.7	in
Cell Temperature (T)	235	F

Table 2.4- Reservoir Fracture Conditions

Fracture height(h)	300	ft
Fracture width (w)	0.8	in
Cell Temperature (T)	235	F

To convert the field rate into the lab rate we use the values from Table 2.3 and 2.4. We first calculate the flow rate in one wing of the fracture for a total production rate of 7000 bbl/d. Table 2.5 shows the lab flow rates for different reservoir conditions.

$q = 7{,}000\ bbl/d$

$$q_{1-wing} = \frac{7{,}000\ bbl/d * 158.987\ l/bbl}{24 * 60\ \min/d * 2} = 386.42\ l/\min \quad (flow\ one\ wing\ of\ fracture)$$

$$N_{re} = \frac{w * u * \rho}{\mu} \quad where \quad u = \frac{q}{A} = \frac{q}{2 * h * w}$$

To calculate injection rate in the lab, we set

$$N_{re,field} = N_{re,lab}$$

which gives us,

$$\frac{q}{h}(lab) = \frac{q}{h}(field)$$

$$q_{lab} = \frac{q_{field}}{h_{field}} * h_{lab} \Rightarrow \frac{386.42 * 1.75}{300 * 12} = 0.174\ slm/m$$

Table 2.5- Laboratory Flow Rates for Different Reservoir Rates

Reservoir Flow rate, bbl/d	Lab Flow rate, l/min
7000	0.175
15,000	0.375
30,000	0.75

2.4 Comparison of Laboratory Conditions

The development of fracture conductivity testing technique has come a long way in terms of equipment and procedure. Cooke (1975) conducted some of the first tests to measure fracture conductivity. For his tests he developed an apparatus that measured residue per volume of fracturing fluid with which he introduced a correlation to calculate gas flow through the propped fracture by considering inertial and turbulence effects. In the experiment, proppant was packed in a vertical position as shown in Fig. 2.10. In 1989, API published the standard process where they introduced thin metal plates between which they packed proppant. Stimlab replaced the metal plates with an inch and a half thick core of Ohio sandstone which allowed a filter cake to build up (Penny 1987). Fivman (2007) introduced a three inch height core sample for conductivity measurements. The reason for doing this was to allow better control of leakoff through the rock sample and provide a more realistic scenario to the field. Although all these experiments did a good job in measuring short-term conductivity of proppant packs, an apparatus or procedure for long term conductivity was never put in

place. When different tests were performed to study long term conductivity it was found that, pressure and temperature have a detrimental effect on conductivity and this was not obvious in short term tests. In 2007, the ISO 13503-5, was developed, based on the API RP-61, was published and that set up the procedure and apparatus for a conductivity test to be considered long term.

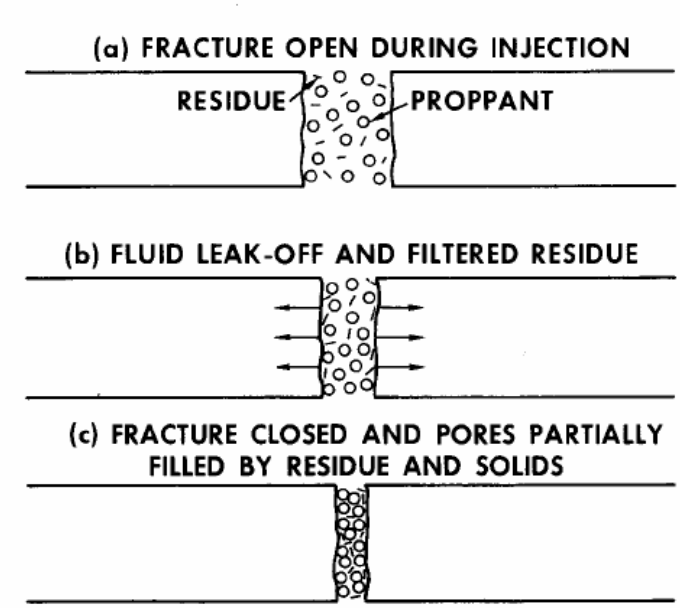
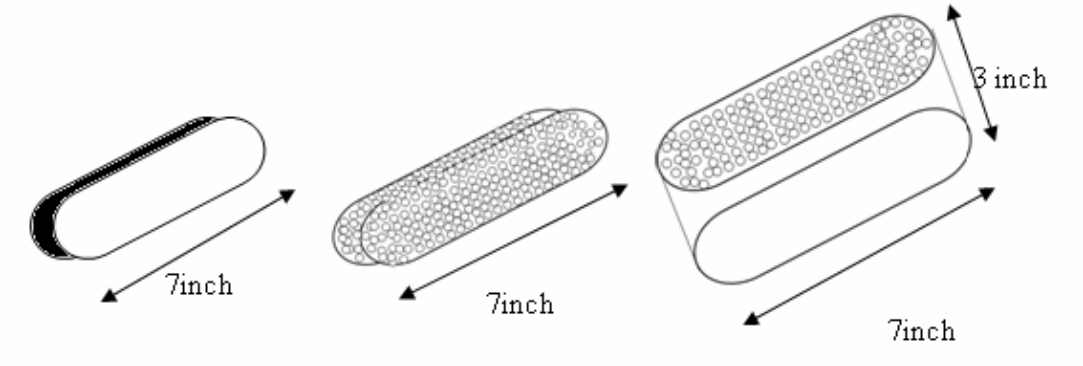


Figure 2.10- Cooke (1975) model to simulate proppant packing

Figure 2.11 shows the development of the core samples with the different experiments. To measure conductivity, different mediums have been used. Roodhart (1986) was the first to propose gas while API and Penny were the first to use brine water as the fluid of choice with flow rates of 1-10 ml/min. In this experiment mineral oil with a viscosity of 10 cp was used. Flow rates were calculated between 0.174 and 0.75 l/min.



a) API RP61, 1989 b) Penny, 1987 c) Pongthunya, 2007

Figure 2.11- Core sample size comparison

2.5 Experimental Output

2.5.1 Surface Profile

3D images of the core sample were generated with the aid of the profilometer. These images represent the surface profile of the rock after applying closure stress on the proppant pack. The images are represented with a color scale, which corresponds to a loss of thickness due to proppant or erosion, with values ranging from -0.05 to 0. inches. Examples of the images generated are shown in Fig. 2.12.

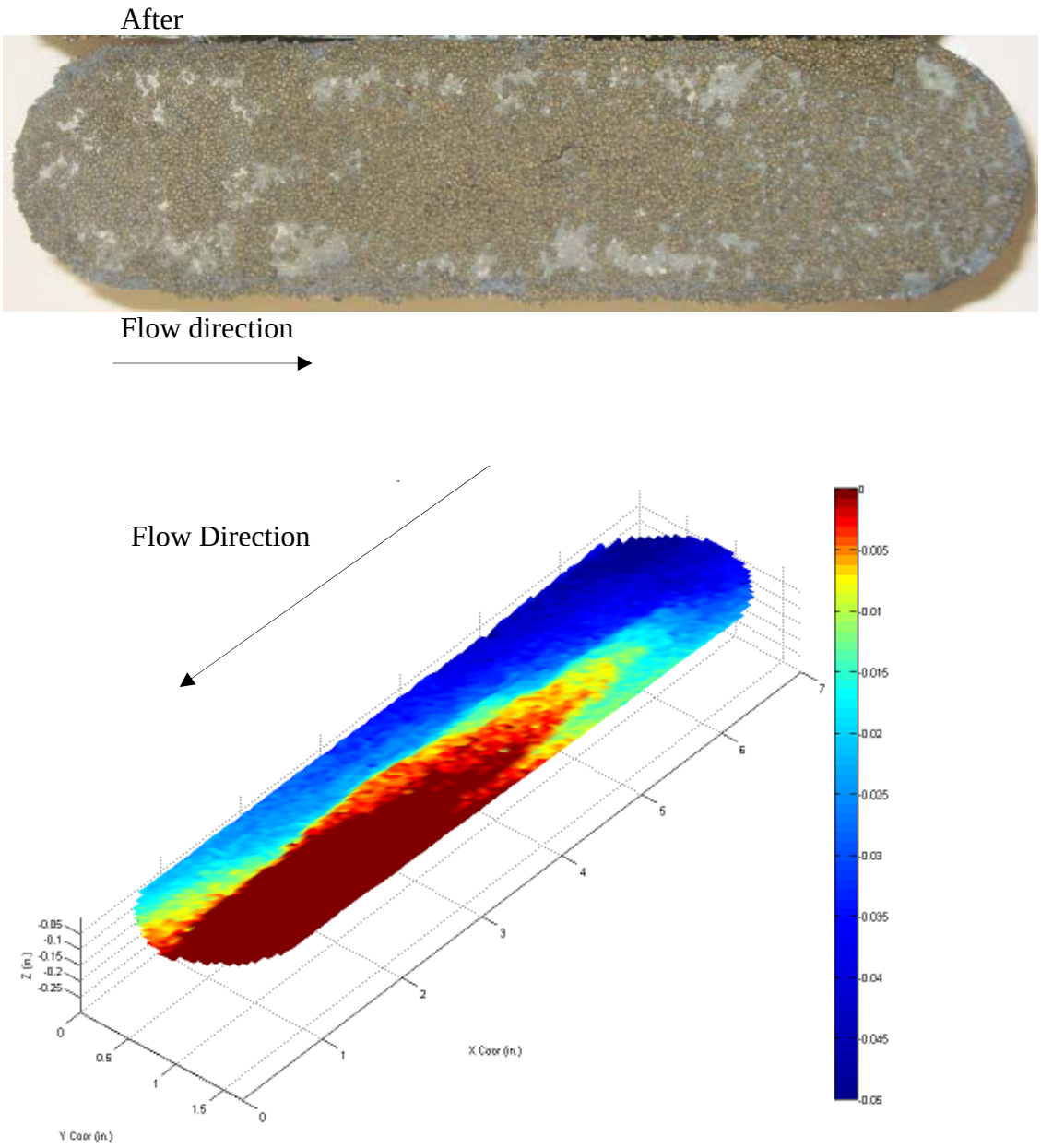


Figure 2.12- Photograph and 3D surface image of a core sample after applying closure stress and flowing oil

CHAPTER III

EXPERIMENTAL RESULTS AND DISCUSSION

We conducted the experiments using Berea sandstones wherein a high proppant concentration pack was placed manually between two core samples and through which a cross-linked gel was injected at 235°F. These experiments were run to set-up and test the procedure for this project. The 8 lb/ft^2 test was repeated to evaluate the consistency of our results and experiments. For each test, fracture fluid was pumped at the beginning and conductivity was measured while varying closure stress. The conductivity values of each experiment are presented in Appendix A. All experimental conditions of this study are summarized in Table 3.1.

Table 3.1- Summary of Experimental Conditions

Test No.	Proppant Concentration, lb/ ft^2	Temperature, °F	Oil Viscosity	Duration
1	4	235	3	Short term
2	8	235	3	Short term
3	8	210	10	Short term
4	8	210	10	Long term

3.1 Experimental Repeatability

To set up our procedure and apparatus, we first followed the recommendations of the ISO 13503-5. Previous studies for measuring long term conductivity did not accurately replicate actual reservoir conditions and therefore to account for the reservoir being studied, it was decided to use mineral oil with similar viscosities and

flow rates. Due to the lack of published data using similar procedures and the need to evaluate our equipment and test cell conditions, we ran identical tests to see if our conductivity values were comparable. Test 3 was run for approximately 1.5 hours and therefore Fig. 3.1 shows the conductivity values attained from both tests after about 1.5 hours. The results show that even though our goal is to study long term conductivity, our experimental setup is capable of testing, accurately and consistently, frac-pack conductivity.

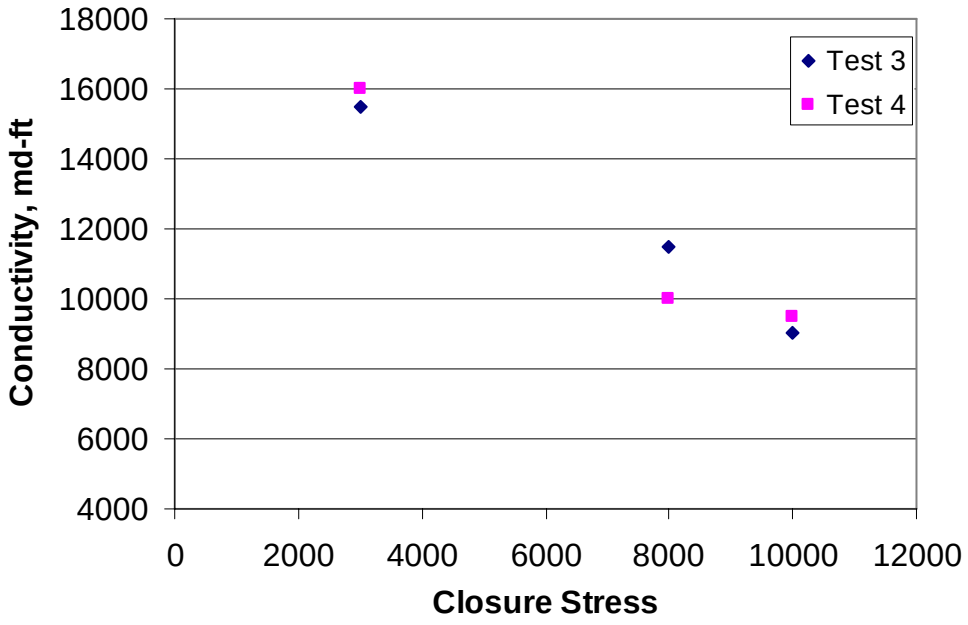


Figure 3.1- Comparison of conductivity values from 8 lb/ft^2 test after 1.5 hours

3.2 Long Term Frac-pack Conductivity

Frac-packs are high proppant concentration fractures and are expected to have higher conductivities. Conductivity measurements taken for an hour or two do not provide an accurate estimate of frac-pack conductivity and therefore running these tests for over 20 hours at each stress is essential to better understand the effects of flow and proppant crushing. In this experiment, we placed a proppant concentration of 8 lb/ft^2 in between two Berea cores that acted as a fracture. A 37.5 lb/Mgal cross-linked fluid was pumped into the fracture with leakoff through the cores at a temperature of 235°F. Closure stress was applied to the cell after which 10 cp mineral oil was then pumped through the fracture to study clean-up and proppant pack behavior. It was noticed that clean-up took about 5 minutes due to the fluid being pumped, followed by which conductivity values were recorded. Figs. 3.2, 3.3 and 3.4 shows the conductivity curve with time for Test 4.

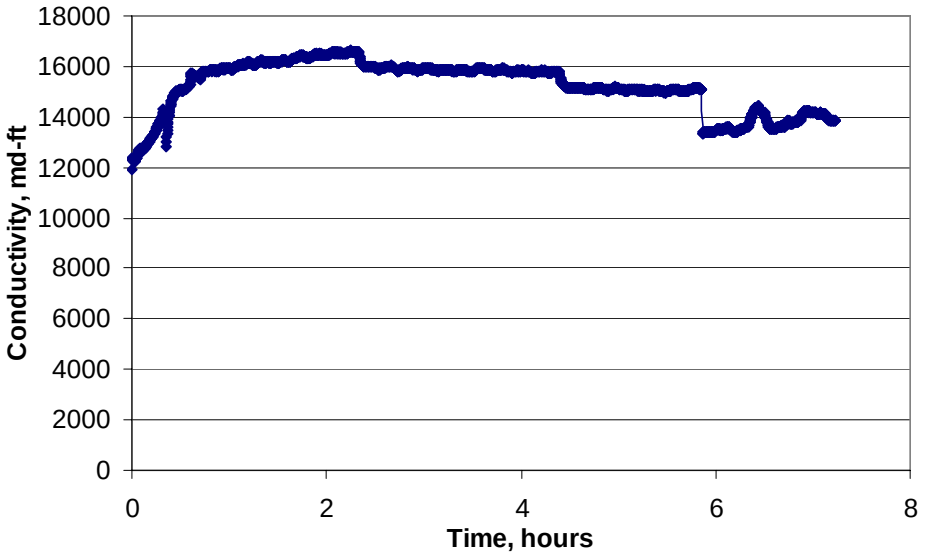


Figure 3.2 - A long term frac-pack conductivity analysis (3000 psi)

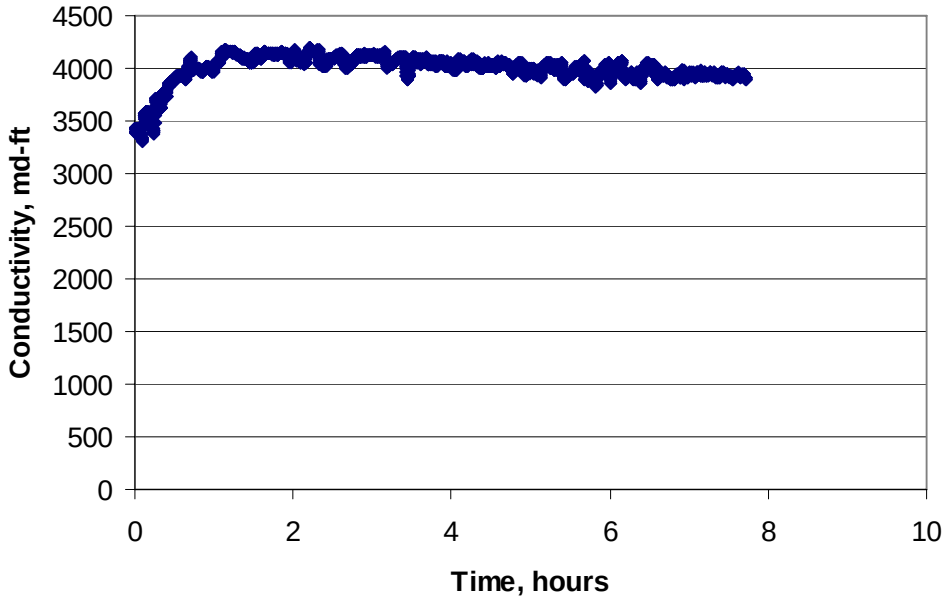


Figure 3.3 - A long term frac-pack conductivity analysis (10000 psi)

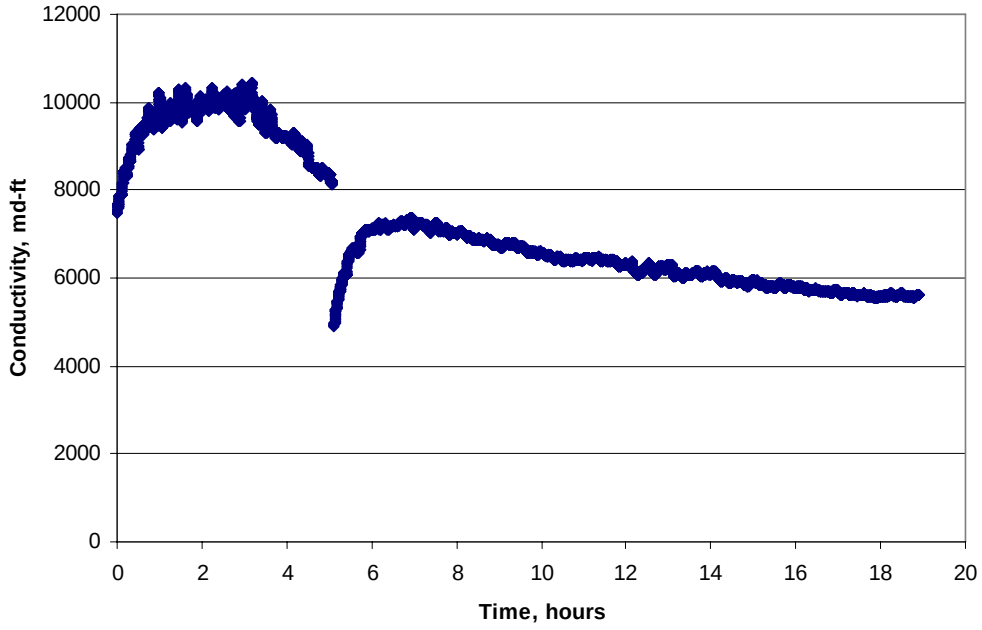


Figure 3.4 - A long term frac-pack conductivity analysis (8200 psi)

At 8200 psi, the test was run over 18 hours and initially we see an increase in conductivity. This is due to the initial heating of oil in place. About three hours into the conductivity measurements we see a gradual decline in conductivity values. The conductivity curve continues declining with time but after about 17 hours it begins to flatten and approach a consistent value when approaching 19 hours. The break at 4 hours is caused by re-starting the experiment the next day. Figs. 3.5 and 3.6 below illustrates how the proppant was distributed in a typical experiment.

Figure 3.5- Proppant distribution in the fracture

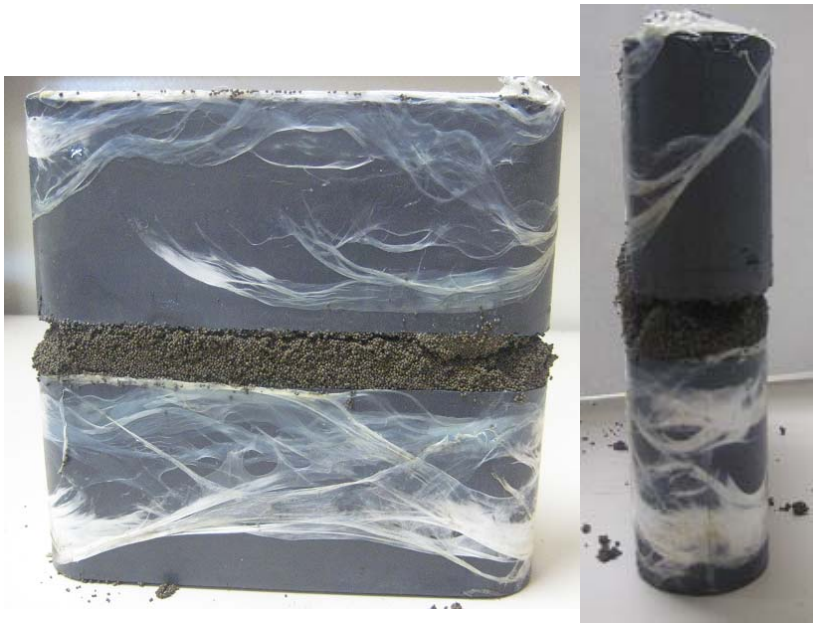


Figure 3.6- Side and front view of the core sample with 8 lb/ft^2 of proppant

3.3 Effect of Closure Stress and Proppant Concentration on Final Conductivity

A big part of this study is to analyze the effect of closure stress and varying proppant concentrations on frac-pack conductivity especially in the presence of high temperature. When the well is first completed, the initial closure stress is relatively low as pore pressure is high but as the well begins producing and the pore pressure decreases, the effective closure stress acting on the fracture increases dramatically. To study the effect of increasing closure stress, we applied a load of 3000 psi on the cell immediately after pumping. Conductivity measurements were taken at 3000 psi, 8000 psi and 10,000 psi.

Fig. 3.7 illustrates how conductivity decreases with increasing closure stress. This decreasing trend can be explained as higher stresses lead to proppant crushing. Due to high velocities, these crushed pieces can plug up pore spaces slowly over time. Higher stresses can also cause re-arrangement of the proppant pack thereby reducing effective permeability. Increasing the proppant concentration from 8 lb/ft^2 to 4 lb/ft^2 is shown to yield higher conductivity values. This can be attributed to the fact that you have a larger area of higher permeability which will further help maintain production and control sand.

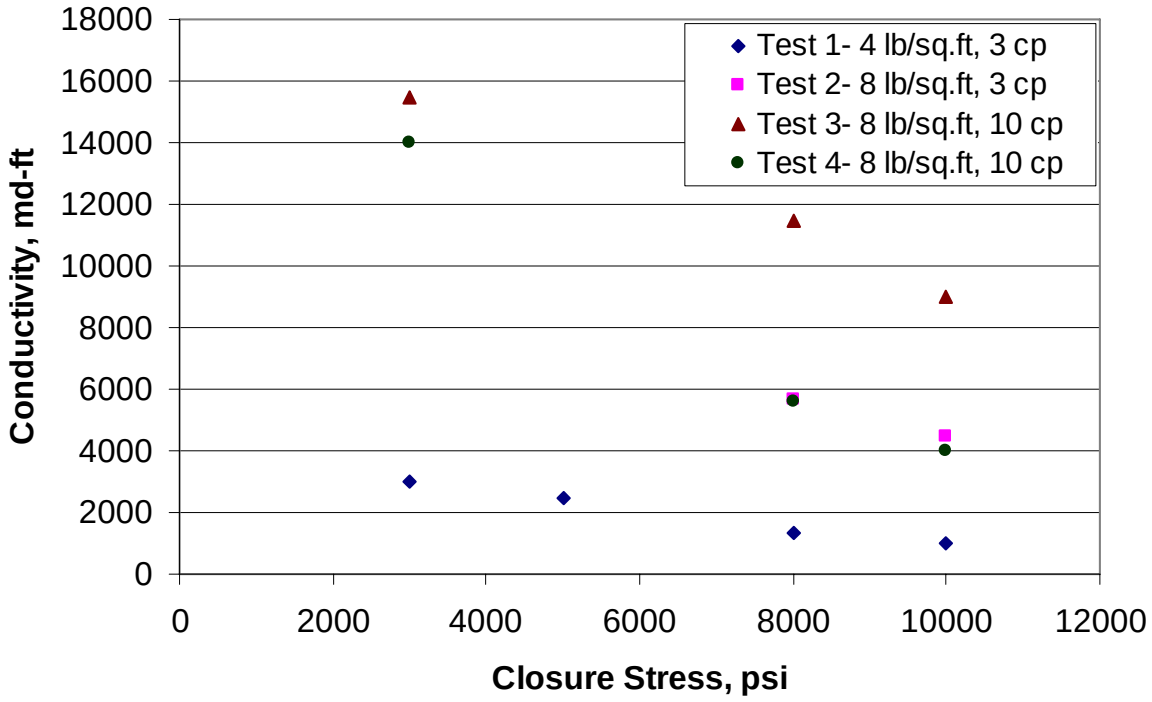


Figure 3.7 – Conductivity values for different closure stresses

3.4 Effect of Flowing Time on Conductivity Results

The length of time spent on conductivity analysis is found to be a major factor in attaining accurate and reliable information. Test 3 was run for approximately 1.5 hours and Test 4 was run anywhere from 8 - 19 hours. These two experiments had similar test conditions and Fig. 3.8 shows the conductivity results from these tests.

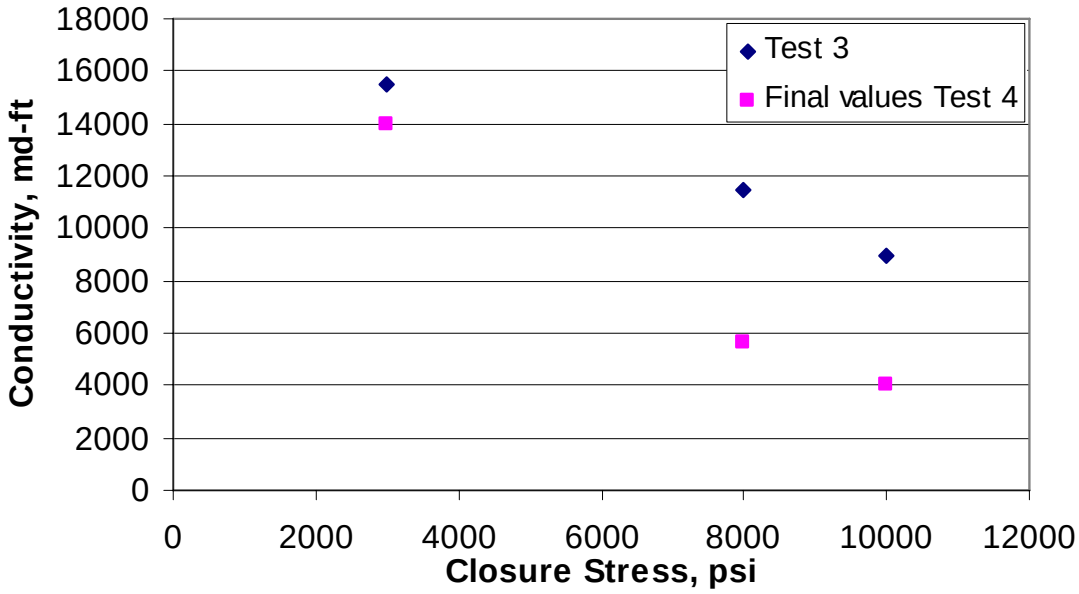


Figure 3.8 – Conductivity measurements for experiments of different duration lengths

It is evident from Fig. 3.8 that running these tests for a longer period of time shows the true effects of long term closure stress. Tests run for shorter periods of time tend to depict higher that expected conductivities which can mask the well productivity and sustained efficiency of the stimulation.

3.5 Comparison with Previous Study

Long term conductivity analysis have been published in many papers before but tests with high proppant concentrations and conductivity measurements performed with mineral oil, which is representative of reservoir fluid, have never been done. Carbo Ceramics has studied long term fracture conductivity of 16/30 high strength proppant at 2 lb/ft^2 using 2% KCl as the fluid. The flow rates used in these tests were in the range of 1-10 ml/min and the procedure followed the ISO 13503-5. The comparison of the conductivity with previous study is shown in Fig. 3.9.

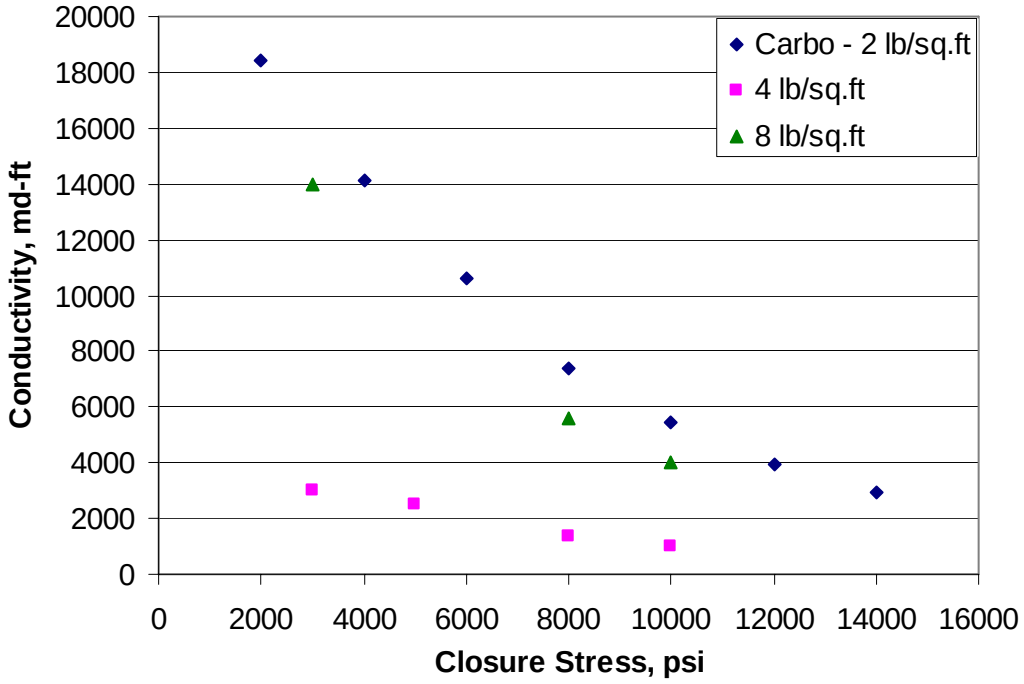


Figure 3.9 - Comparison of conductivity values with industry tests

From Fig. 3.9 it is evident that conductivity values attained from tests performed with the industry approved procedures are much higher than those measured from our experiments. Ideally, higher proppant concentrations should yield higher conductivities and that is evident with the 4 lb/ft^2 and 8 lb/ft^2 but those values do not correlate with the 2 lb/ft^2. With time, conductivity values tend to drop and reach a much lower value than initially calculated. This maybe the result of temperature, pressure and/or proppant crushing which at higher flow rates can lead to migration of proppant particles thereby reducing conductivity with time. The higher conductivity values attained by Carbo Ceramics maybe the result of using low flow rates which might not take into account Non-Darcy effects. Flow rates used by Carbo Ceramics equate to a reservoir flow rate of about 4-40 bbl/d where as in this experiment 170 ml/min equates to 7000 bbl/d. Another difference is the pumping of fracture fluid through the proppant pack. The presence of residual polymer can lead to gel damage and further reduction of conductivity which is absent in Carbo Ceramics' experiments. The decline in conductivity for the 4 lb/ft^2 experiment follows a much different slope than for the 8 lb/ft^2 case. The values at 8000 psi and 10,000 psi seem accurate but for the 3000 psi and 5000 psi they show a much higher decline. This could be attributed to a greater effect of closure stress on conductivity decline for a 4 lb/ft^2 than on an 8 lb/ft^2 or simply due to error in the data obtained from the transducers.

CHAPTER IV

CONCLUSIONS AND RECOMMENDATIONS

4.1 Conclusions

A long term frac-pack conductivity apparatus was developed, setup and tested. A set of preliminary experiments were conducted to perfect the procedure and study the effect of relevant variables on conductivity measurements. The following conclusions are made based on the observations from the study:

1. The testing apparatus was tested and experiments repeated with satisfying results. This apparatus can be used with different fracture fluids and proppant concentrations to find optimal conditions of fracturing.
2. Increasing closure stress will decrease frac-pack conductivity. This can be attributed to the compaction of the proppant pack and crushing of proppant which leads to lower effective permeability and width.
3. Running conductivity tests for short time periods provides conductivity values that are deviated from final results. After running a test for approximately 20 hours, we reached stable conductivity measurements, which were lower than published data for tests of shorter durations under the same conditions.
4. Higher proppant concentrations in the fracture yield higher fracture conductivities due to greater widths and a larger area of higher permeability.

5. Conductivity values from published data were found to be much higher than those attained from this experiment. This could be attributed to lower flow rates and the absence of any fracture fluid being pumped through the pack.

4.2 Recommendations

With these experiments we have shown that we have an apparatus that can successfully perform frac-pack conductivity testing in a laboratory while replicating field conditions. In this experiment, proppant concentrations of 4 and 8 lb/ft^2 were used at 3000, 8000 and 10,000 psi closure stress. However the duration of time was not sufficient on all tests to accurately estimate fracture conductivity.

For an improved analysis further testing should be done at concentrations of 4, 8 and 10 lb/ft^2 and at closure stresses of 3000, 5000, 8000 and 10,000 psi and for longer periods of time (20+ hours each) to get a better understanding of conductivity decline with increasing closure stress. This will be helpful in identifying an optimal proppant concentration to attain during the actual frac-pack job. Another condition to consider when measuring conductivity would be to cycle closure stress after reaching 10,000 psi. During the life of a well, shut-ins and start-ups lead to a decrease and increase in effective closure stress on the fracture and therefore studying its effect would be helpful in efficiently producing the well.

These tests used Berea core samples and 2% KCl based fracture fluids. It would be useful to use the core sample from the formation and sodium bromide, NaBr, as base fracture fluid to accurately represent final stimulation job.

Although these tests provide a better understanding of long term frac-pack conductivity, additional experiments are suggested with the above conditions to get information that can be used to produce a successful frac-pack and an economic well.

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APPENDIX

A.1-Experimental data for Test 1 – 4 lb/ft^2, 235 °F, Berea Sandstone

Figure A.1.1- Side view of the core sample for Test 1

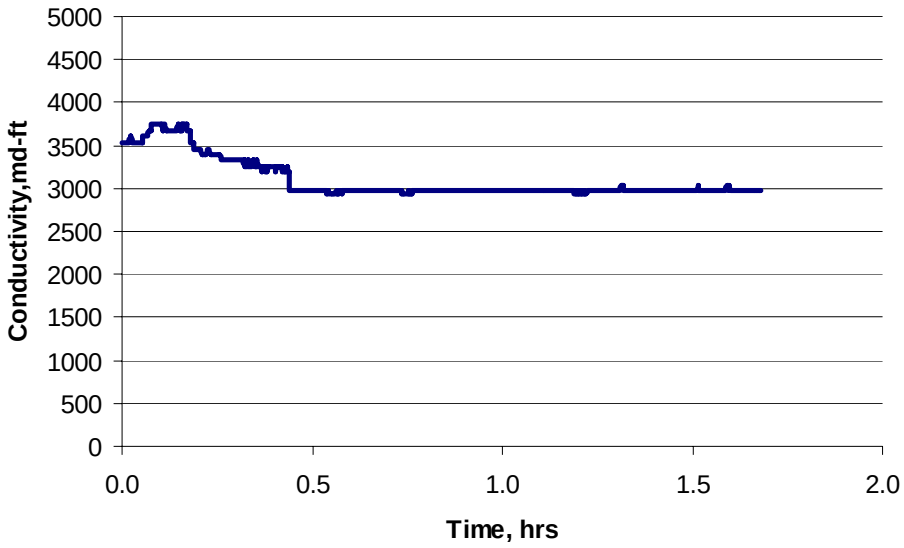

Figure A.1.2- Long term frac-pack conductivity analysis for Test 1 (3000 psi)

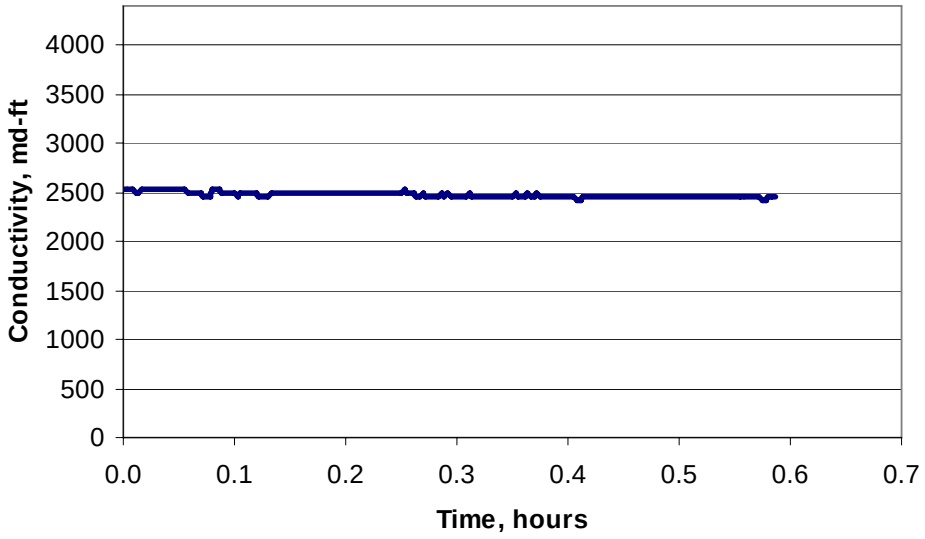

Figure A.1.3- Long term frac-pack conductivity analysis for Test 1 (5000 psi)

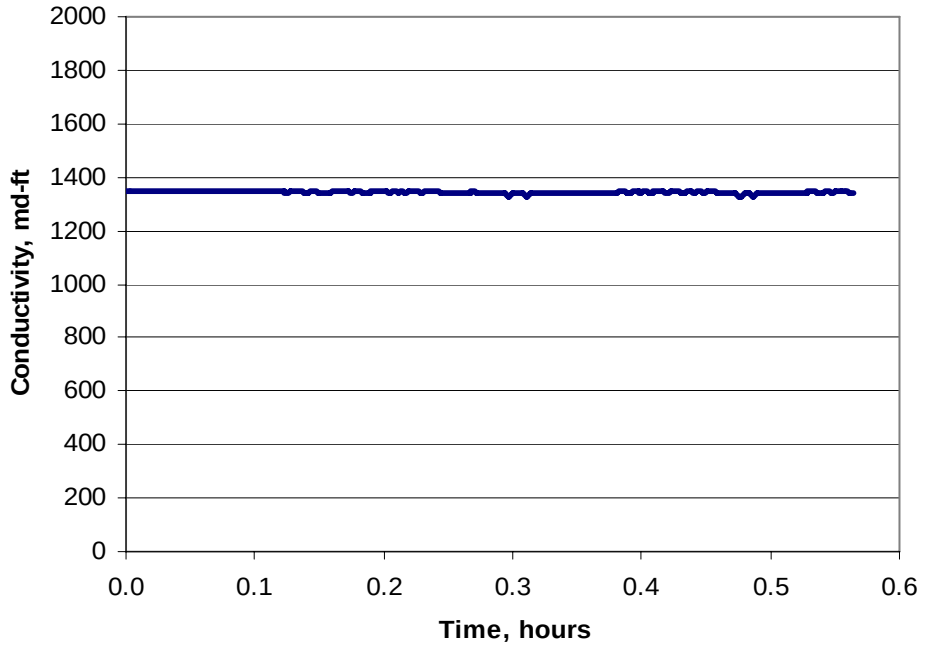

Figure A.1.4- Long term frac-pack conductivity analysis for Test 1 (8000 psi)

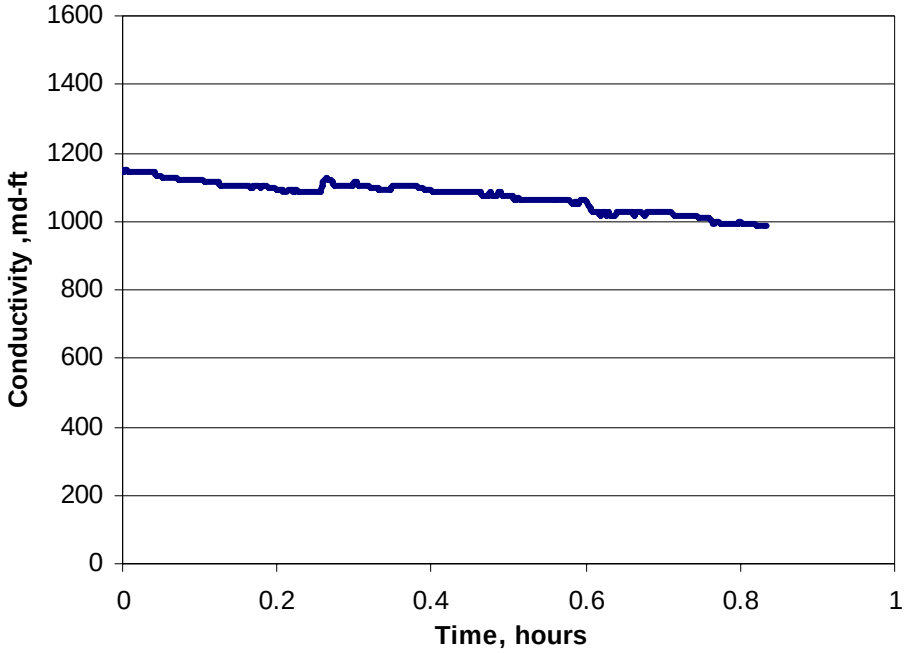

Figure A.1.5- Long term frac-pack conductivity analysis for Test 1 (10000 psi)

A.2-Experimental data for Test 1 – 8 lb/ft^2, 235 °F, Berea Sandstone

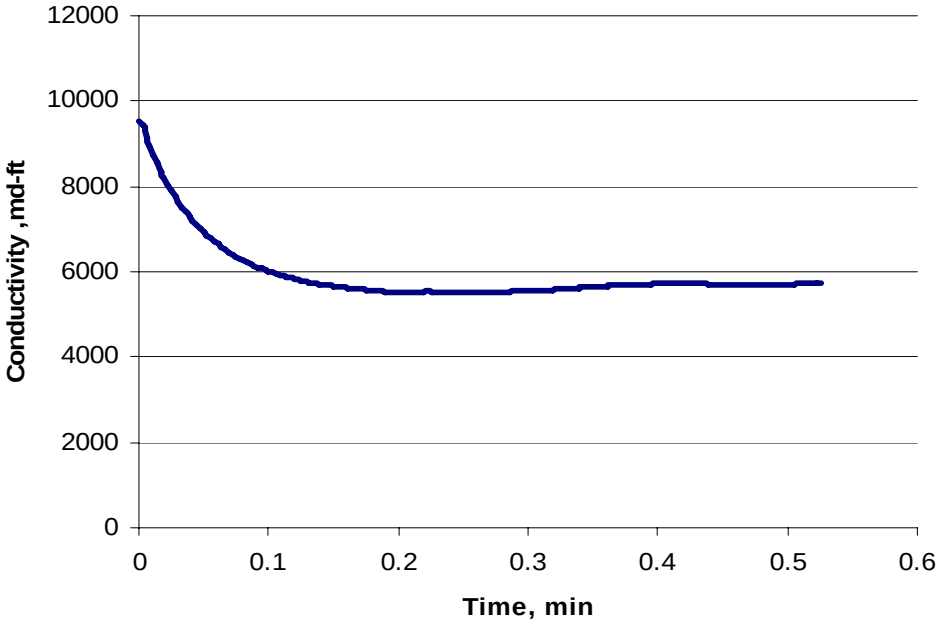

Figure A.2.1- Long term frac-pack conductivity analysis for Test 2 (8000 psi)

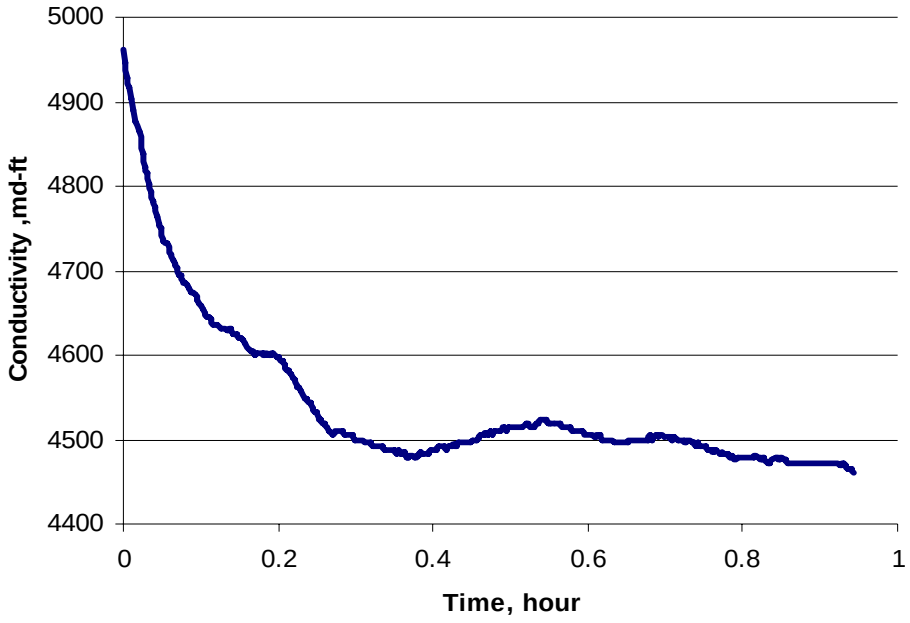

Figure A.2.2- Long term frac-pack conductivity analysis for Test 2 (10000 psi)

A.3-Experimental data for Test 3 – 8 lb/ft^2, 210F, Berea Sandstone

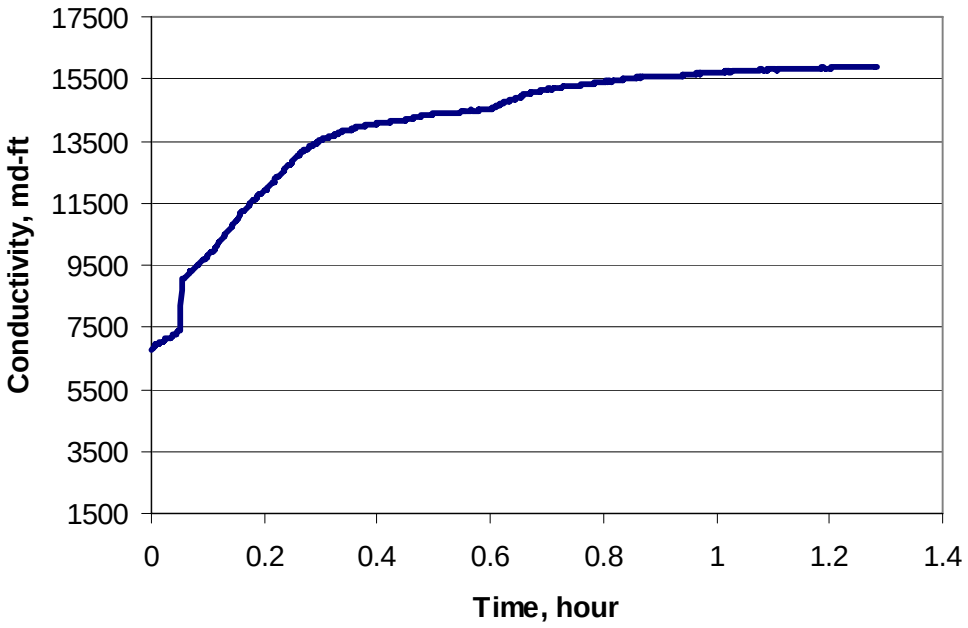

Figure A.3.1- Long term frac-pack conductivity analysis for Test 3 (3000 psi)

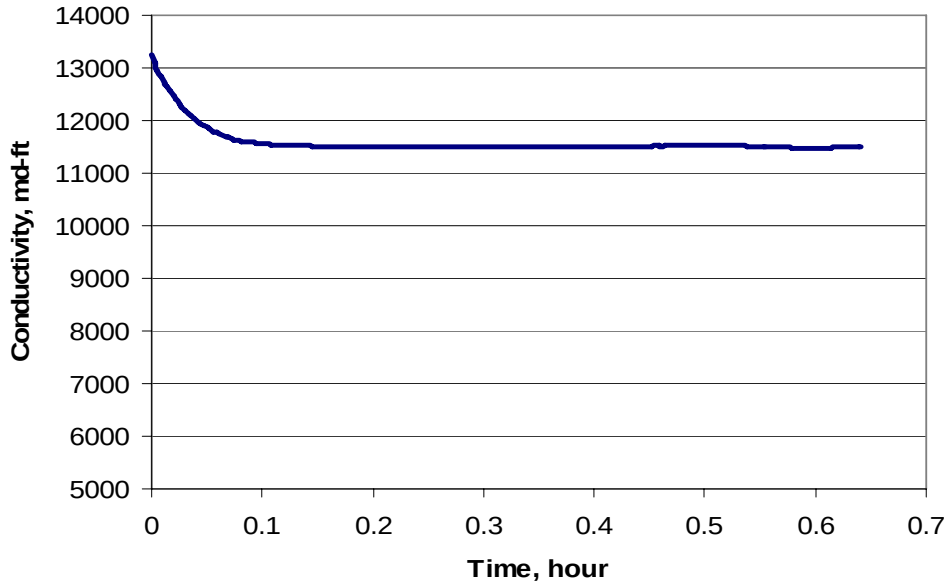

Figure A.3.2- Long term frac-pack conductivity analysis for Test 3 (8000 psi)

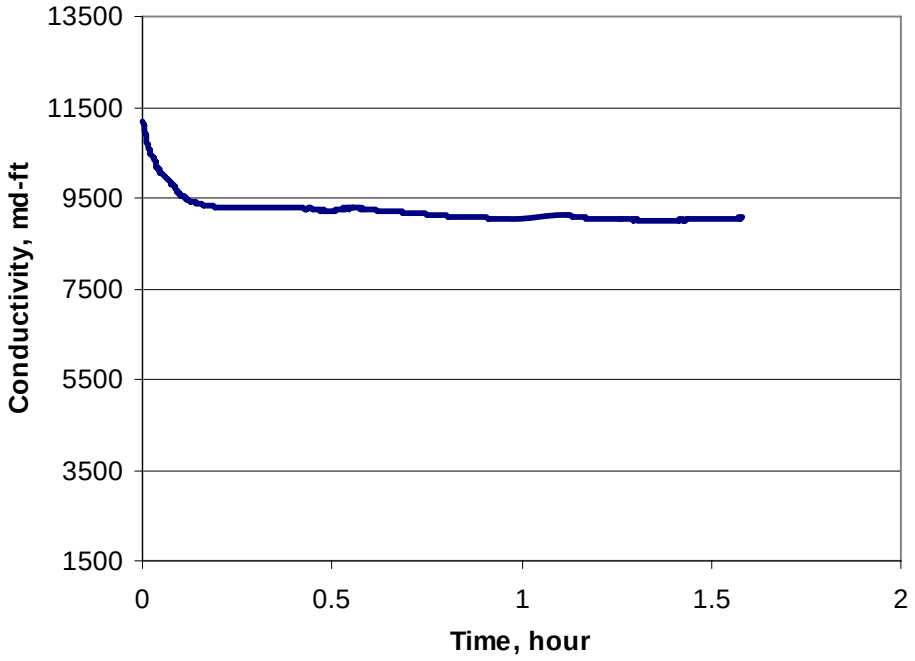

Figure A.3.3- Long term frac-pack conductivity analysis for Test 3 (10000 psi)

A.4-Experimental data for Test 4 – 8 lb/ft^2, 210F, Berea Sandstone

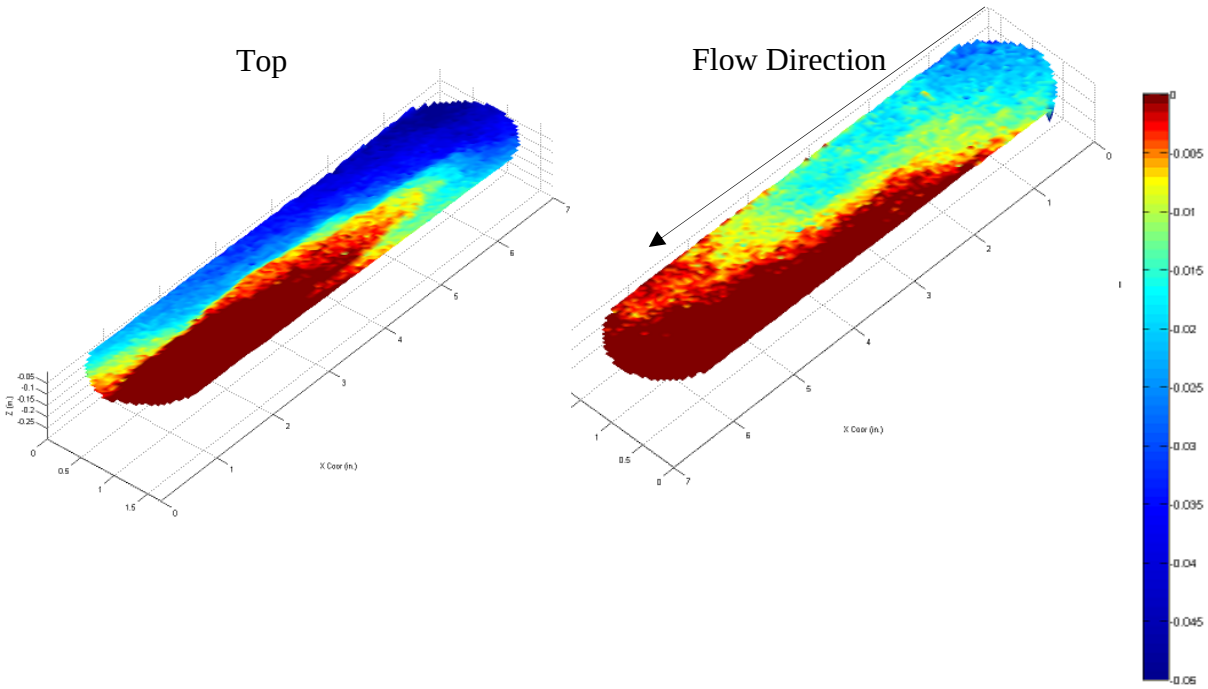

Figure A.4.1- Surface profile of core sample from Test 4

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